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Mr. Jerry Lesperance
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Dear Jerry:

Enclosed are copies of five papers that discuss the results of the "HGP-A Geothermal Wellhead Environmental Monitoring" Contract (No. 14937). I hope that these will provide sufficient information to satisfy the reporting requirements on this project.

Should you have any questions regarding these papers please give me a call.

Sincerely yours,

Donald Thomas

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encl.

PROCESS CHEMISTRY MONITORING AT THE HGP-A POWER PLANT:
ANALYTICAL RESULTS, PROCESS PROBLEMS AND MODIFICATIONS

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ABSTRACT

The HGP-A generator plant began operations on June 12, 1981 and came on-line on a continuous basis on March 1, 1982. During this period process problems were identified and, in most cases, plant modifications have eliminated the difficulties. Silica in the brine was stable at a pH 7.5, however, at a pH above 9.5 deposition of silica was triggered in a brine disposal system and required abandonment of the hydrogen sulfide abatement process originally proposed for the brine system. The steam phase sulfide abatement system for standby conditions was 90% effective, although superheat in the treatment system reduced abatement efficiency. Brine carryover through the separator was very low; however, scale deposition on the turbine blades resulted in substantial damage to the turbine. Non-condensable gases in the condenser were weakly partitioned into the liquid phase, and about 99% were carried into the off-gas treatment system which was found to be approximately 99% effective.

INTRODUCTION

Start-up operations at the HGP-A generator facility on the island of Hawaii were initiated on June 12, 1981; the power plant began providing power to the utility grid on a continuous basis on March 1, 1982. During this shakedown period and continuing to the present, a number of mechanical and process problems have arisen from the geothermal fluid characteristics or from proposed operational procedures that were incompatible with the geothermal fluids. Most of the initial problems have been resolved and modifications are continuing on the plant facility to correct those that remain.

BRINE PROCESS MONITORING

The HGP-A well, which powers the generator facility, has an output capacity of approximately 23,000 kg/hr (50,000 lb/hr) of brine and 23,000 kg/hr (50,000 lb/hr) steam. The total fluid flow from the well is directed into a centrifugal separator/demistor vessel (Fig. 1) where the steam

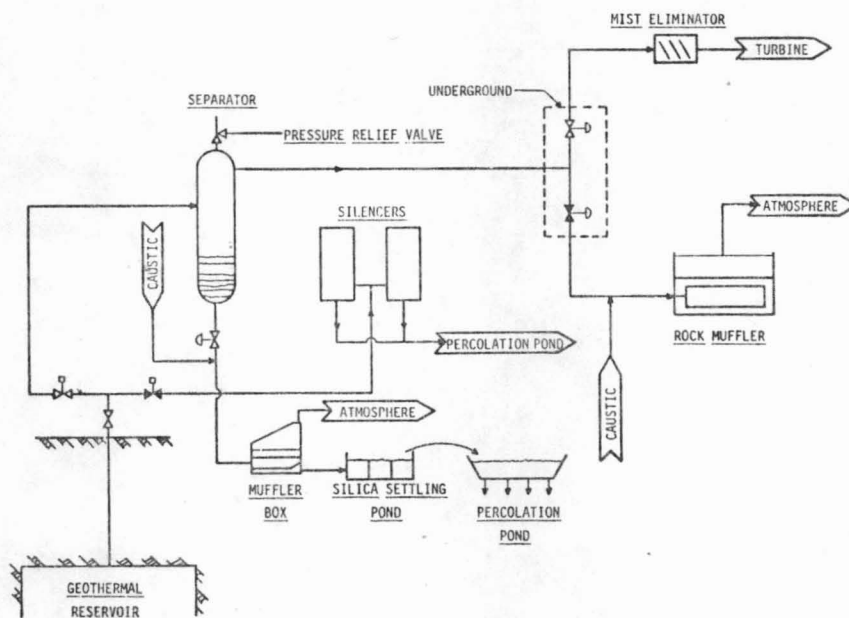


Fig. 1 HGP-A Geothermal Generator Project steam supply process.

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and brine flows are separated at approximately 1,200 kPaa (175 psia). The observed major element chemical composition from the separator is summarized in Table I. Although a detailed interpretation of the fluid chemistry has not been completed, several general observations can be made. The total dissolved solids content has increased substantially since flow was initiated in June 1981. This increase may be the result of increased seawater intrusion into the production aquifers or, alternatively, it may reflect an increasing fraction of steam formation from the single phase reservoir fluid as the flash front migrates away from the wellbore. It is also noteworthy that silica concentrations in the brine have decreased, rather than increased, since the early production flow. The decrease is thought to result from rapid reequilibration of the reservoir silica concentrations to lower temperatures encountered in the flash zone and in the wellbore. If reequilibration is controlling the silica concentrations, it is probable that substantial silica precipitation is occurring both within the flash zone and in the wellbore; this situation may, in the long term, reduce the output capacity of the HGP-A well.

TABLE I. MAJOR ELEMENT CHEMISTRY OF HGP-A FLUIDS (mg/kg)

	Cl ⁻	Na	K	Mg	Ca	SO ₄ ⁼	SiO ₂
6/17/81	1593	806	148	.061	15.9	50	1233
9/4/81	3700	2190	250	0.1	72.	63	795
Well Shut In	--	--	--	--	--	--	--
12/22/81	3261	1745	281	0.038	58.3	ND	1004
2/5/82	4226	2253	364	0.054	84.4	ND	850
4/5/82	5119	--	--	--	--	--	--

From the separator, the brine is passed through a pressure reduction valve into an atmospheric flash tank. The remaining liquid fraction is passed through a silica settling tank and then into a percolation pond. The steam phase formed is presently being emitted to the atmosphere. The brine phase fed into the low-pressure flash tank contains approximately 30 ppm hydrogen sulfide and approximately 60 ppm carbon dioxide; about 90% to 98% of these gases are partitioned into the steam phase formed in the flash tank, resulting in an appreciable pH change in the brine (from about 7.4 to 8.5). The steam discharge, as a result of the gas loss from the brine, becomes a small but significant source of hydrogen sulfide emissions from the plant. The increase in brine pH occasioned by the gas loss also has significant impact on the silica present in the liquid phase. Whereas the dissolved silica in cooled (non-flashed) samples of brine appeared to be stable indefinitely, the increased pH of the flashed brine triggered silica polymerization resulting in the formation of a moderately stable colloidal suspension of silica polymers. Under these conditions, silica precipitation in the silica settling tank is very slow; after nearly five months of flow, the silica cake on the walls of the pond is less than 2 cm thick.

The hydrogen sulfide emissions in the steam phase from the flash tank were considered sufficiently large to justify the application of abate-

ment procedures. The proposed process was an adjustment of the brine pH to approximately 10 pH units immediately downstream of the pressure reduction valve. This procedure was effective in reducing the sulfide emissions from the brine. However, it also destabilized the colloidal silica formed at pH 8.5; the colloidal suspension rapidly flocculated to form a moderately viscous sludge having a water content of approximately 95% to 99%. The sludge formed was sufficient to fill the silica settling tank in approximately 48 to 72 hours and, if passed through the settling tank, caused an immediate and drastic reduction in the performance of the percolation ponds. Although a number of procedures for handling the silica sludge were investigated, none proved to be economically workable, and thus direct caustic injection into the brine as hydrogen sulfide abatement procedure was abandoned. Work is currently under way to construct a hood and treatment stack for the hydrogen sulfide emissions from the brine flash tank.

STEAM PROCESS MONITORING

The steam fraction from the separator, during plant stand-by conditions, is diverted through a pressure reduction valve and into a rock muffler. The non-condensable gas concentrations present in the steam phase are summarized in Table II. The sulfide production rate from this well amounts to approximately $\frac{1}{2}$ a metric ton per day in the steam phase; thus it was necessary to apply hydrogen sulfide abatement procedures to the geothermal steam emitted to the atmosphere. The abatement technique applied was to inject a 10% solution of sodium hydroxide into the low-pressure steam line upstream of a static mixer spool. This procedure was found to be about 90% effective at a mole ratio of 3 sodium hydroxide to 1 hydrogen sulfide. Although this may not be the peak efficiency for this system, we did find that substantially increased caustic injection rates provided only a minimal improvement in the abatement efficiency.

TABLE II. GAS CHEMISTRY IN HGP-A STEAM

	CO ₂	H ₂ S	N ₂	H ₂	CO
6/14/81	670	609	130.5	9.	~1
2/8/82	964	1297	125.	12.9	~1

The degree of superheat in the steam was found to be a very important factor in the efficiency of the hydrogen sulfide abatement procedure. During the initial start-up period, insufficient water was added to the steam line downstream of the pressure reduction valve and as a result, caustic was being injected into a superheated steam. Under these conditions, the efficiency of the caustic abatement procedures was reduced by 30% to 50% and substantial back pressures were created (due to solids deposition) throughout the low-pressure system. The latter effect may have precipitated the failure of a temporary port in the rock muffler box. Further work with the system indicated that sulfide abatement and system back pressures were optimized with a slight excess (10%-20%) of desuperheat water being injected. Additional testing of this abatement system is planned.

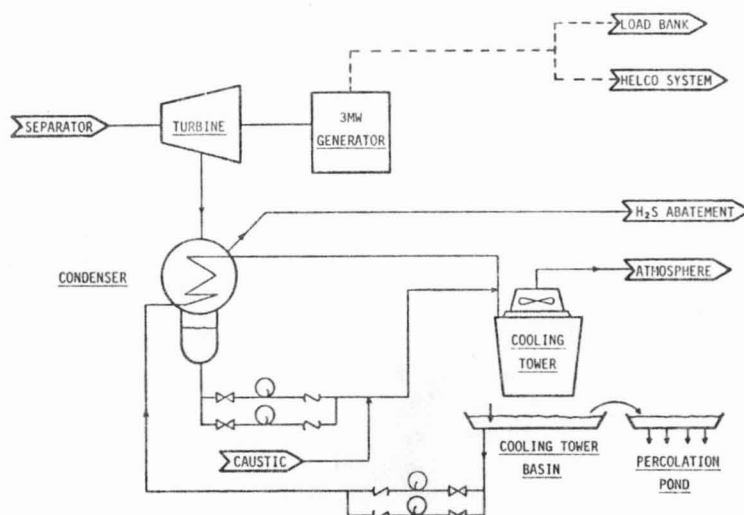


Fig. 2 HGP-A Geothermal Generator Project output and heat rejection.

The steam phase from the separator, under normal conditions, passes through a secondary demistor vessel and into the turbine through trip and control valve manifolds (Fig. 2). To determine the fraction of brine carried past the separator and demistor, the chloride concentration in the steam phase was tested immediately downstream of the plant separator and downstream of the demistor. Silica concentrations were tested there as well. The chloride levels observed in the steam samples were generally between 0.3 ppm and 0.7 ppm; sample blank levels (using distilled water) for the analytical procedures were generally about 0.1 ppm to 0.2 ppm. These chloride levels corresponded to about 0.01% to 0.02% brine carryover in the steam phase.

In spite of the low brine carryover observed in the steam phase, scale material was discovered on the turbine blades during the initial start up period of the facility. The turbine scale material was discovered subsequent to a generator start-up procedure that resulted in excessive turbine vibration that inflicted substantial damage to the turbine rotor and shaft assembly. Removal of the turbine casing revealed that significant amounts of scale material had been deposited on the turbine blades and on the internal components of the turbine housing. Analysis of the scale material indicated that it was primarily a mixed iron oxide with smaller amounts of iron sulfides. An evaluation of the plant chemistry and operating procedures up to the excessive vibration incident suggests that the source of the scale was the piping and manifold section between the turbine inlet and the block valve upstream of the demistor vessel. During the start up, this section of pipe, which is constructed of mild steel, had been exposed alternately to both sulfide-bearing steam and to the atmosphere a number of times due to

required modifications on the control valve assembly. This treatment of the pipe had allowed substantial quantities of iron oxide scale to form, which was subsequently carried into the turbine and mechanically deposited on the blades. To alleviate this problem during future turbine starts, the plant piping was modified to allow the entire steam manifold, down to the turbine inlet, to be blown clear after any extended period of turbine shutdown. The effectiveness of this modification has not been determined; turbine vibration at critical speed has not increased substantially during subsequent turbine start-up procedures.

The spent steam from the turbine is passed through the exhaust duct into a stainless steel surface condenser maintained at a pressure of about 0.8 kPaa (6 in. Hg abs.). Analysis of the steam condensate formed indicated that the liquid had a pH of about 4.5 and that approximately 0.6% of the hydrogen sulfide present in the steam was carried into the liquid phase. This latter value contrasts sharply with steam plant performance at Geysers where as much as 30% of the hydrogen sulfide remains in the steam condensate. The virtual absence of ammonia in the steam from HGP-A probably accounts for the observed difference in hydrogen sulfide solubilities.

The condensate liquid is pH-adjusted to approximately 9 and then pumped into the cooling water return line as make-up water for the cooling tower. The pH of the cooling water was found to be extremely important in minimizing corrosion of the mild steel piping used in the cooling water lines and to inhibiting emission of hydrogen sulfide from the cooling tower.

The non-condensable gases from the condenser are removed through a two-stage ejector assembly

and are injected into an incinerator backed by a packed column scrubbing tower. The hydrogen sulfide fraction of the gases is incinerated to sulfur dioxide, which is subsequently removed by sodium hydroxide treatment in the packed column. During the initial start-up of this abatement system, insufficient air flow into the incinerator resulted in an incomplete reaction of the hydrogen sulfide to sulfur dioxide, leading to the following reaction: $2\text{H}_2\text{S} + \text{SO}_2 \rightarrow 3\text{S}^\circ + 2\text{H}_2\text{O}$. Elemental sulfur formed very rapidly, reduced the scrubber column flow capacity, and required a shut down of the system for removal and replacement of the tower packing. Modification of the air blower system to provide an excess mole ratio of oxygen in the incinerator apparently has eliminated this problem.

Although the abatement efficiency of the incinerator scrubber was quite high (>99%), the gaseous emissions from the column were found to carry a significant quantity of sulfur particulates. Because this was considered to be a source of visual pollution, piping was installed to transmit the stack gases to the air intake of the cooling tower. Passage of the gas through the cooling water cascade removed a substantial fraction of the sulfur particulate and diluted the remainder to the point that it was not visible in the cooling tower plume. No adverse effects on the cooling tower water from this procedure have been observed.

PRESENT OPERATION

At the present time the power plant is operating at a capacity of about 2.8 MWE with an overall plant hydrogen sulfide abatement efficiency of approximately 98%. Work is currently under way to reduce the condenser back pressure to 0.5 kPaa (4 in. Hg abs.) or less in order to bring the plant capacity up to 3 MWE. Modifications are also under way on the brine steam emission system that will attempt to improve the total hydrogen sulfide abatement efficiency of the facility to better than 99%.

ACKNOWLEDGMENTS

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